EXECUTIVE SUMMARY
2004/05 WINTER – BULK TRANSMISSION APPRAISAL

The AEP East bulk transmission system is expected to perform as designed in accordance with ECAR and NERC Planning and Operating Criteria to provide a reliable delivery system for power to supply AEP's 2004/05 winter peak load. The AEP East bulk transmission system is also able to function as a reliable pathway for scheduled power transfers across our system. The following discussion is an overview of the expected performance of the AEP East bulk transmission system for Winter 2004/05. Detailed summaries of performance are provided in subsequent pages for each of the AEP East Transmission Planning Regions (Columbus, Fort Wayne, and Roanoke).

The AEP transmission system was assessed for both forecasted peak load and extreme weather (106% of forecasted load) modeled conditions for winter 2004/05. In addition, "stressed cases" were developed for each sub-area identified as the three AEP East Transmission Planning Regions (Columbus, Fort Wayne, and Roanoke). These stressed cases, described in more detail in the Performance Analysis section of this report, consisted of heavy transfers and generation dispatch scenarios to identify AEP's transmission system limits and operating constraints. Thermal and voltage analyses were then performed on the base and stressed cases.

The AEP East bulk transmission system configuration for Winter 2004/05 remains relatively unchanged as compared to the previous winter. The following differences are expected:

1. Connected load is modeled less than [redacted]
2. A new [redacted] interconnection was established with [redacted] by looping the [redacted] circuit [redacted] into the [redacted] The [redacted] was upgraded as part of this project.
3. The [redacted] will be upgraded to a [redacted] by mid-December.
4. The [redacted] which failed last spring, was replaced with a [redacted]
5. The [redacted] was connected at the [redacted] in the [redacted] circuit.
6. TVA increased ratings on both the [redacted]
7. DVP installed series capacitors on both the [redacted] lines to improve stability at [redacted] and [redacted]

Some areas of the Roanoke, Ft. Wayne, and Columbus Transmission Planning Regions could experience [redacted] Areas of [redacted] occur during [redacted] could also occur if [redacted] periods of [redacted] and forecasted [redacted]

The most critical area of concern continues to be [redacted] Combinations of EHV outages, in conjunction with power deliveries resulting in a large [redacted] across the AEP transmission system, could result in a [redacted] absent proactive operator intervention. Close monitoring in the [redacted] Region must and will be maintained.

The [redacted] circuit could reach its voltage limit set by the [redacted] guidelines with minimal power transfers to the [redacted] It is the limiting [redacted] facility [redacted] in conjunction with [redacted] Single contingencies that may result in for transfers to the [redacted] circuit are flows approaching limitations of the [redacted] circuits. [redacted]

Also, in the [redacted] Transmission Planning Region, the [redacted] and the [redacted]

The [redacted] could experience overloads during heavy [redacted] This transformer bank has been derated based on recent manufacturer thermal capability studies. These studies are currently under review by AEP. [redacted]

Also, in the [redacted] Transmission Planning Region, the [redacted] and the [redacted] the [redacted] circuits can experience overloads during [redacted]

Revisions to the NERC criteria for calculating relay trip settings, stemming from the August 14, 2003 blackout, have reduced the rating on several [redacted] The [redacted] are now limited by relay trip settings and could be constraints during heavy transfers and double contingencies. The NERC criteria is a very conservative approach assuming voltage much lower than expected during these conditions. Transmission Planning is reviewing the application of these minimum relay trip settings consistent with the voltage conditions expected during [redacted] conditions.

Also, in the [redacted] Transmission Planning Region, the [redacted] could experience overloads during heavy transfers and double contingency conditions.

In general, [redacted] is expected to be acceptable on the AEP East bulk transmission system for Winter 2004/05. For limitations, [redacted] will be implemented as appropriate to ensure the continued reliable operation of the transmission system. Details of the sub-area appraisals can be found in the individual Columbus, Fort Wayne, and Roanoke Transmission Planning Region Appraisals included in this report.

FORT WAYNE TRANSMISSION PLANNING REGION
2004/05 WINTER -- BULK TRANSMISSION APPRAISAL

By Chris Shaffer

Summary

Various system conditions were simulated under projected 2004/05 winter conditions to evaluate the system performance of the Fort Wayne Transmission Planning region. System performance for the 2004/05 winter season is expected to be improved as compared to the 2004 summer and is a result of increased seasonal facility ratings, reduced loading in the Indiana and Michigan service area and local area system improvements and modifications. Winter facility ratings are calculated based on an average winter ambient temperature of 2° C (35°F) as opposed to the summer facility ratings, which are calculated based on an average summer ambient temperatures of 35° C (95°F). The difference in these calculations results in increased winter facility ratings. Forecasted conditions for the 2004/05 winter season include a total sub-transmission load of [redacted] in the I&M service area, which is approximately [redacted] of the 2004 summer forecasted I&M sub-transmission load and is approximately [redacted] lower than the 2003/04 winter forecasted I&M sub-transmission load. Several system improvements and modifications have occurred since the 2003/04 winter season. These enhancements and expected abnormal conditions are listed below:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

- [redacted]

This report focuses on discussing the system responses to credible outages, in conjunction with variable load levels and transfers. Actions to alleviate the adverse conditions caused by the outages are also discussed. Additional information on these outage scenarios can be found in the detailed Performance Analysis section of this report.

Projected System Performance:

System Modeling and Analysis:

Peak load models were constructed for the 2004/05 winter using the most recent available data from internal and external sources regarding load, generation, and interchange. "Stressed" cases were created by adding transfers at [redacted] for use in AC thermal and voltage analysis. Contingency analyses were performed on the peak load model as well as the stressed transfer cases. Descriptions of the stressed cases are provided in the Performance Analysis section of this report.

Transfer Capability Limitations:

First Contingency Incremental Transfer Capabilities (FCITC) were determined for transfer biases in several directions across the Fort Wayne Transmission Planning region. Facilities with a three percent or less distribution were not considered in this analysis. Only credible transfer scenarios that had a significant impact on the Fort Wayne Transmission System were analyzed. Table 1 below is a summary of the FCITC analysis and shows the limiting facility and outage facility pairs for each transfer direction. Transfer directions are representative to the Fort Wayne Transmission Planning region only. Additional details regarding the FCITC analysis can be found in the Performance Analysis section of this report.

Table 1: 2004/05 Winter FCITC Summary

Transfer	Limiting Facility	Outaged Facility	FCITC (MW)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			

Thermal Performance:

Relay trip settings using the newly established NERC standards are reflected in Transmission Planning's system models. The current standard bases the calculation on voltages that are 85% of nominal. This is a very conservative approach since voltages on most AEP EHV circuits will not drop by a 15 % margin under [redacted] scenarios. The minimum relay trip settings increase significantly when using a higher voltage for the calculation. The relay trip settings used in this winter's analysis reflect the current NERC standards with an 8% margin added into the calculation. Transmission Planning is reviewing the application of these minimum relay trip settings consistent with the voltage conditions expected during double contingency and heavy transfer conditions and may revise these ratings accordingly.

<u>South Bend Service Area</u>

The [redacted] line could experience loadings approaching its winter emergency rating under [redacted] conditions to the [redacted] and [redacted] The winter emergency rating for this facility is [redacted] which corresponds to the minimum relay trip setting for this facility. This facility is not expected to be as much of a concern if voltages under contingency conditions are above [redacted] of nominal.

The [redacted] line may exceed its winter emergency [redacted] rating with the [redacted] concurrent with heavy transfers to the [redacted]

[redacted]

Fort Wayne/Marion/Muncie Service Areas

No thermal limitations were identified for the facilities in the Fort Wayne/Marion/Muncie service areas for the expected 2004/05 winter conditions.

Western and Southern Indiana Facilities

The [redacted] line section and the [redacted] under circuit could experience loadings above their [redacted] scenarios concurrent with transfers to the [redacted] have the greatest impact on these facilities. The [redacted] section's is limited to [redacted] by the minimum relay trip setting and the [redacted] is limited to [redacted] by the minimum relay trip setting. The voltage during these conditions is expected to remain higher than 92%, well above the 85% voltage criteria used to calculate the minimum relay trip setting. Therefore, it is not expected that these facilities will be at risk of tripping at these loading levels. Outages involving [redacted]

The [redacted] circuits could experience loadings approaching their [redacted] ratings under [redacted] scenarios and unusually high transfers to the [redacted] or [redacted] outages in combination with an outage of the [redacted] line have the greatest impact on these facilities. All of these facilities are limited by their respective conductor capabilities.

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COLUMBUS TRANSMISSION PLANNING REGION
2004/05 WINTER – BULK TRANSMISSION APPRAISAL

By Bart Taberner

System conditions for 2004/05 winter are expected to be similar to those in 2003/04 winter. Comparisons of base flows, generation, and loads show only minimal change from last winter. Changes in the Columbus Transmission Planning Region and in surrounding regions that could affect flows this winter include:

- AEP's entrance into PJM RTO control
- AEP interchange changes
- Slight loading differences from 2003/04 winter
- AEP generation dispatch

Forecasted peak demand levels are similar to those projected for 2003/04 winter. The projected load is [redacted] for CSP and [redacted] for OP when compared projected load for last winter. Comparisons to summer 2004 projected peak demands show OP is [redacted] and CSP is [redacted] lower for this winter.

Modeled AEP transfer levels for winter 2004/05 are similar to projected interchanges for winter 2003/04 with the following exceptions. [redacted] exports to [redacted] are [redacted] higher as compared to last winter. There is a new [redacted] transfer modeled from [redacted] this winter. [redacted] imports from [redacted] have increased by [redacted] and [redacted] The [redacted] transfer from [redacted] modeled last winter is not modeled for 2004/05 winter making the resultant net import to [redacted] from the [redacted] than a year ago.

Modeled flows decreased by [redacted] on the [redacted] line section while flows increased on the [redacted] and [redacted] paths. The resultant flow bias change toward the [redacted] is generally due to the net import reduction from the [redacted] described above.

Thermal loading concerns should be limited to [redacted] situations coupled with high transfers to the [redacted] with few exceptions.

This assessmentaddresses system responses to credible outages, in conjunction with variations in load levels and transfers, and actions that could be undertaken to mitigate adverse conditions. These outages involve [redacted] facilities and [redacted]

ROANOKE TRANSMISSION PLANNING REGION
2004/05 WINTER – BULK TRANSMISSION APPRAISAL

By Rosalyn Navarro

The Roanoke Transmission Planning Region is anticipated to respond adequately under the forecasted 2004/2005 Winter conditions. The forecasted APCO load for the 2004/2005 Winter season is [redacted] which is less than a [redacted] increase from the 2003/2004 Winter forecasted load of [redacted]

Study results indicate that with all facilities in service and in the absence of heavy transfers to the [redacted] the transmission system in the Appalachian area should perform adequately during anticipated conditions for the 2004/05 winter season. However, certain [redacted] in the Roanoke transmission area (including facilities in neighboring systems) are expected to cause overloads and other problems, especially when [redacted] or [redacted] are heavy through the area. Critical [redacted] include, but are not exclusive to the following:

[redacted]

The potential of [redacted] conditions following [redacted] require that system operators maintain close coordination with neighboring systems to permit the maximum utilization of the interconnected network without jeopardizing the reliability of the Appalachian area transmission system.

Changes since 2003/2004 Winter

Since 2003/2004 winter, the following changes have been made to or around the Appalachian region:

1) Addition of [redacted] that is looped into the [redacted] and [redacted]
2) [redacted] increased ratings on both [redacted] for both winter normal and winter emergency ratings; an increase from [redacted] and [redacted] respectively.
3) [redacted] to compensate for 60% of the lines impedances. The [redacted] were installed to improve the stability performance of [redacted]

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FACILITY RATINGS

The diagrams in the following pages show the normal and emergency ratings for summer and winter (yellow pages) assumed in the SPA studies. For each facility, the listed ratings were determined by the most limiting element(s) either on the line itself, at the terminal stations, or at any intermediate (two-outlet) substation. The ratings were calculated using the criteria summarized below. With the exception of transformers, the summer ambient is 35°C (95°F) and the winter ambient is 2°C (35°F). For transformers, the summer and winter values are 30°C (86°F) and 10°C (50°F), respectively. The emergency ratings are generally based on a 24 hour period.

Buses and Risers

1 MPH wind, Normal-conductor temperature 85°C (Copper), 95°C (Aluminum & ACSR). Emergency-conductor temperature 115°C-120°C (Aluminum & Copper), 130°C (ASCR).

Circuit Breakers

Summer - 105% of nameplate rating
Winter - 130% of nameplate rating

Conductors

2 MPH wind. Normal-conductor temperature 95°C (203°F). Emergency-conductor temperature 130°C-205°C (266°F-401°F).

Current Transformers

Normal - 100% of nameplate rating
Emergency - 100% of nameplate rating

Disconnect Switches

Summer: normal/emergency - 109%/134% of nameplate rating
Winter: normal/emergency - 145%/160% of nameplate rating

Series Reactors

Normal - 100% of nameplate rating
Emergency - 100% of nameplate rating

Series Capacitors

Normal - 100% of nameplate rating
Emergency - 110% of nameplate rating

Wave Traps

Summer: normal/emergency - 102%/107% of nameplate rating
Winter: normal/emergency - 116%/120% of nameplate rating

Transformers

The ratings of all EHV and 345/138 kV transformers were determined on an individual basis by the Transmission Station Engineering and Standards Department. Refer to the Station Standards, Transformer Loading Guide for details of the rating criteria.

Notes

In January 1994 AEP issued Report No. 786 (Rev.), "A Guide for Maximum Temperature and Ampacity of Bare Overhead Conductors." These guidelines establish a range of permissible emergency conductor temperatures for various types of conductors, which in general allow for higher emergency ratings. However, the report cautions that the new temperature limitations may exceed sag limitations. Therefore, although most conductor limitations shown here follow the new guidelines, individual investigation by the Electrical Systems Engineering Division will be requested when planning studies or system conditions indicate possible loading above the "normal" rating.

In some instances where a higher equipment rating was desirable, an individual determination was made by the Electrical Systems Engineering Division.

Tieline ratings are determined by the company owning the limiting element(s), and are mutually agreed upon by AEP and the interconnecting company.

Most ratings listed for Columbus Southern Power Company lines were determined by CSP personnel prior to incorporation into the AEP system, using different criteria. Ratings for such lines will be reevaluated as needed.

Ratings for non-AEP facilities are the latest provided by the companies which own them.

Steady state stability and voltage loadability limited facilities may have several ratings depending on the conditions, contingency, or the actions required in the operating procedure. The following diagrams show the rating that reflects the base case conditions. See the appropriate operating procedure for further details.

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ABBREVIATIONS

I. ORGANIZATIONS

ECAR	East Central Area Reliability Coordination Agreement
AEWC	Allegheny Energy Wheatland (CIN Interconnection)
AEWI	Allegheny Energy Wheatland (IPL Interconnection)
AEP	American Electric Power System
AP	Appalachian Power Company
CS	Columbus Southern Power Company
IM	Indiana Michigan Power Company
KP	Kentucky Power Company
OP	Ohio Power Company
AMPO	American Municipal Power - Ohio, Incorporated
AP	Allegheny Power
BREC	Big Rivers Electric Corporation
BUCK	Buckeye Power, Incorporated
CIN	Cinergy Corporation
CGE	The Cincinnati Gas & Electric Company
PSI	PSI Energy, Incorporated
CPP	Cleveland Public Power
DEVI	Duke Energy Vermilion (CIN Interconnection)
DLCO	Duquesne Light Company
DPL	The Dayton Power and Light Company
EKPC	East Kentucky Power Cooperative, Incorporated
FE	FirstEnergy
CEI	The Cleveland Electric Illuminating Company
OE	Ohio Edison System
TE	The Toledo Edison Company
HE	Hoosier Energy Rural Electric Cooperative, Incorporated
IMPA	Indiana Municipal Power Agency
IPL	Indianapolis Power & Light Company
IPRV	Illinois Power Riverside (AEP Interconnection)
ITC	International Transmission Company
DECO	The Detroit Edison Company
LGEE	LG&E Energy Corporation
KU	Kentucky Utilities Company
LGE	Louisville Gas & Electric Company
MCCP	Municipal Cooperative Coordinated Pool - Michigan
MCV	Midland Cogeneration Venture
MECS	Michigan Electric Coordinated System
METC	Michigan Electric Transmission Company
CONS	Consumers Energy
NIPS	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
SIGE	Southern Indiana Gas and Electric Company
WVPA	Wabash Valley Power Association
FRCC	Florida Reliability Coordination Council
EQ-FRCC	Powerflow Equivalent of FRCC Region
MAAC	Mid-Atlantic Area Coordination Group
AE	Atlantic Electric (Conectiv)
BG&E	Baltimore Gas and Electric Company
DP&L	Delmarva Power and Light Company (Conectiv)

JCP&L	Jersey Central Power and Light Company
METED	Metropolitan Edison Company
PECO	PECO Energy
PENELEC	Pennsylvania Electric Company
PEPCO	Potomac Electric Power Company
PJM500	PJM Interconnection - 500 kV System
PP&L	Pennsylvania Power & Light Company
PSE&G	Public Service Electric and Gas Company
UGI	UGI Utilities
MAIN	Mid-America Interpool Network
AMRN	AMEREN Corporation
CIPS	Central Illinois Public Service Company
UE	Union Electric System
CE	Commonwealth Edison Company
CILCO	Central Illinois Light Company
CWLP	City Water Light and Power (Springfield, Illinois)
EEI	Electric Energy, Incorporated
EMO	East Missouri Subregion of MAIN
EQ-MAIN	Partial Powerflow Equivalent of MAIN Region
IMEA	Illinois Municipal Electric Agency
IP	Illinois Power Company
NI	Northern Illinois Subregion of MAIN
SCILL	South Central Illinois Subregion of MAIN
SIPC	Southern Illinois Power Cooperative
WUMS	Wisconsin-Upper Michigan Systems Subregion of MAIN
MAPP	Mid-Continent Area Power Pool
EQ-MAPP	Powerflow Equivalent of MAPP Region
NPCC	Northeast Power Coordinating Council
EQ-NPCC	Partial Powerflow Equivalent of NPCC Region
NYISO	New York Independent System Operator
NYPP	New York Power Pool
HONI	HydroOne (Canada)
IMO	Independent Market Operator (Canada)
SERC	Southeastern Electric Reliability Council
AECI	Associated Electric Cooperative, Incorporated
BCA	Batesville Control Area
CPLE	Carolina Power & Light Company (East)
CPLW	Carolina Power & Light Company (West)
DENL	Duke Energy, North Little Rock
DOE	Department of Energy
DUKE	Duke Energy Control Area
LAGN	Louisiana Generating Company
EQ-SERC	Partial Powerflow Equivalent of SERC Region
NCEMC	North Carolina Electric Membership Cooperative
SC	Santee Cooper (South Carolina Public Service Authority)
SCEG	South Carolina Electric & Gas
SOCO	Southern Control Area
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas Subregion of SERC
VAP	Virginia Power
SPP	Southwest Power Pool

EQ-SPP	Powerflow Equivalent of SPP Region

II. STUDY TERMS

ATC	Available Transfer Capability
CRV	Curtailment Reference Value
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GSRF	Generation Shift Response Factor
IITC	Installed Incremental Transfer Capability
LEER	Lake Erie Emergency Re-dispatch Procedure
LMP	Locational Marginal Pricing
LODF	Line Outage Distribution Factor
MEN	MAAC-ECAR-NPCC
MET	MAIN-ECAR-TVA
MMWG	Multiregional Modeling Working Group
NDC	Net Demonstrated Capability
NSC	Net Seasonal Capability
NERC	North American Electric Reliability Council
NITC	Normal Incremantal Transfer Capability
NTTC	Normal Total Transfer Capability
OTDF	Outage Transfer Distribution Factor
PAR	Phase Angle Regulator
PTDF	Power Transfer Distribution Factor
QFW	Queenston Flow West Interface in Ontario Hydro
RCP	Reliability Coordination Plan
SCITC	Second Contingency Incremental Transfer Capability
TDF	Transfer Distribution Factor
TLR	Transmission Loading Relief Procedure
VAST	VACAR-AEP-Southern-TVA
VEM	VACAR-ECAR-MAAC

SPECIAL PROCEDURES

I. INTRODUCTION

This subsection lists and briefly describes various operating procedures that have been developed to enhance the performance in specific areas of the bulk power system. The procedures described herein, all of which result in changes in network configuration or generation dispatch levels, generally are implemented to achieve one or more of the following goals:

1. To reduce facility loadings to within equipment thermal capabilities;
2. To maintain acceptable transient stability margins at generating stations;
3. To improve area reliability without exceeding the short circuit capabilities of circuit breakers;
4. To insure adequate voltage levels or steady state stability margins are maintained.

Procedures relating to AEP facilities and tielines with neighboring systems are found in Part II. The listing is separated by AEP's Transmission Planning Regions. Operating procedures developed by AEP's neighbors are described in Part III. Here the listing is alphabetic by company. The provision of a consolidated listing of new and established procedures should aid system operators in maximizing utilization of the bulk power system. Likewise, planning engineers should benefit in terms of the more accurate modeling of projected system conditions obtained by including likely operator responses to particular system conditions in planning studies.

Additional details of the procedures may be available by contacting members of East Transmission Planning.

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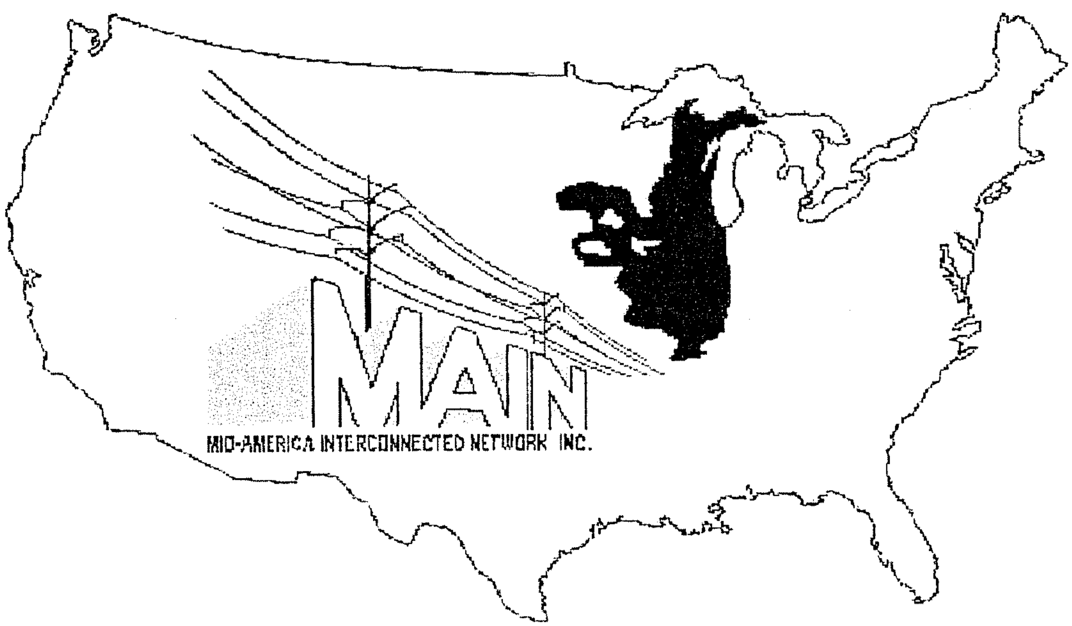
MID-AMERICA INTERCONNECTED NETWORK INCORPORATED

REGIONAL RELIABILITY COUNCIL

2004 MAIN
Summer Transmission
Assessment Study

Including
MAIN-ECAR-TVA, MAIN-MAPP-SPP, **and** MAIN-SERC WEST
Interregional Appraisals

April, 2004



Summary of Definitions*

Definition	Key Facilities** Out of Service	Thermal Rating Of Limiting Facility
First Contingency Incremental Transfer Capability (FCITC) (But not greater than IITC)	One	Emergency
Installed Incremental Transfer Capability (IITC)	None	Normal
First Contingency Total Transfer Capability (FCTTC) (FCITC plus base power transfers)	One	Emergency

* See MAIN Guide No. 2
** Anticipated during transfers

Availability of Additional Studies

All requesting companies in MAIN, the MAIN, MAPP and SPP Coordination Centers, AEP, and TVA have received a full set of computer study results. This data is available for reference if questions arise about specific system conditions that were studied.

The transfer capability results found here are not the same as the Available Transfer Capability (ATC) or Available Flowgate Capacity (AFC) posted on the appropriate transmission provider's OASIS page. For further understanding, see the section entitled "Understanding and Use of this Report."

If system conditions occur or are expected which are not covered in this report, the MAIN companies are encouraged to contact the MAIN Coordination Center or their respective reliability coordinator for assistance in conducting appropriate power flow studies. The MAIN Coordination Center has computer facilities, the 2004 summer power flow base case, and the capability for providing power flow study results in 4-7 hours under emergency conditions. For nonemergency conditions a 24 hour turn-around time can be met.

2004 MAIN
Summer Transmission
Assessment Study

Including

MAIN-ECAR-TVA, MAIN-MAPP-SPP and MAIN-SERC WEST
Interregional Appraisals

April, 2004

Prepared by

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CONTENTS

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Understanding and Use of this Report

This report summarizes the results of a study of expected MAIN 2004 summer peak conditions. The study was made, and the report was prepared, by the MAIN Transmission Assessment Studies Group (TASG). The report defines transfer capability, provides expected system transfer capabilities, and offers general operating guidance.

Limitations on the Use of Reported Transfer Capability Values

It is important to note that the transfer capabilities reported in this study are benchmarks to gauge the transmission system strength based on a snapshot of the expected summer peak conditions. The reported values are not intended to be absolute limits to system operation for all system conditions. Therefore, judgment should be used in reviewing these reported transfer levels before assuming that these values are either optimistic or pessimistic for use in daily system operation.

The study results provide a reliability assessment of the transmission system's ability to support area, regional and subregional imports and exports. However, these import and export values apply only for the conditions simulated in the study and therefore may not represent the worst case. Since actual system conditions at any point in time may vary considerably from conditions modeled in the study, users should base their decisions upon conditions or factors as they actually exist. Discussion with transmission planners of the individual systems and the MAIN Coordination Center or respective reliability coordinator may be helpful in making such decisions.

The incremental transfer capability values reported in Exhibit D-1 are nonsimultaneous, meaning that only one incremental transfer was studied in addition to those transfers described in the base case interchange schedule of Exhibit C-2. Many factors can affect the incremental transfer capabilities on a daily basis, including any deviations from base interchange schedule, assumed source and sink points and their participation percentages in the transfer schedules, and system conditions represented in the base case power flow model (system load levels, generation dispatch, outaged transmission elements, changes in transmission network configuration, etc.).

For this transmission reliability study, emergency operating guides are utilized. These guides are considered for use if a load serving entity is in jeopardy of dropping firm load. Consequently, these emergency guides are not available for routine commercial transactions. In addition, the following practices used in this transmission reliability study are different than those used in studies to calculate ATC for commercial purposes:

- Modeling of base case transactions that have no associated transmission service has been permitted. This is being done to allow peak load conditions to be modeled as well as simulating other scenarios for reliability evaluations. The modeling of these transactions may result in transmission element loadings that differ from those that exist in the models used to calculate ATC. This practice may result in different transfer capabilities.

- Some regional and subregional (areas) transfer directions studied do not represent directions for which transmission service is sold. The source and sink points associated with these regional and subregional (areas) transfer directions may result in distribution factors and limits that are different than those obtained for the transfer directions for which ATC is sold.

- The use of emergency operating guides is allowed in the calculation of transfer capabilities in this report.

- The use of margins (TRM & CBM) are not considered in the calculation of transfer capabilities in this report.

- Some firm transmission reservations were not considered in this study because either the generation capacity requiring the use of these reservations was not modeled or they were partial path reservations.

Therefore, the transfer capability results found here are not the same as the Available Transfer Capability (ATC) or Available Flowgate Capacity (AFC) posted on the appropriate transmission provider's OASIS page.

Operating Guides

Operating guides are considered available for use in determining transfer capabilities if they are implemented on a pre-contingency basis or on a post-contingency basis without operator intervention. In addition to this, operating guides requiring operator intervention on a post-contingency basis are also considered applicable if the affected system will withstand any resulting overloads until the operating guide is implemented and no undue burden is placed on neighboring systems.

One or more operating guides may be assumed to be available/implemented to obtain the transfer capability levels reported on an interregional as well as area and subregional basis. However, depending on the specific outage, implementation of related operating guide(s) will be required. Some of these operating guides have been in use for a considerable period of time. The operating guides identified in this study, **except for those involving generation redispatch**, have been verified by the MAIN TASG and are considered effective, to a varying extent, in relieving the loadings on the limiting transmission facilities or increasing transfer capabilities. Table A-0 shows the effects on FCITC values with and without the implementation of unverified operating guides that involve redispatch.

For this study, the operating guides are assumed available for all transfer directions, if transfer capability is enhanced. In reality, some operating guides may require a redispatch of generation or undesirable transmission operation which would impose a burden on the utility with the limiting facility, whether or not that utility is contractually involved in the particular transfer.

The operating guide description will clearly state if the guide is for emergency use only.

Five operating guides used in this report to determine transfer capabilities have been designated for emergency use. Four emergency operating guides were used in the 2003 summer study. The descriptions of these guides appear in Exhibit D-2. It is recommended that the user of this report review these guides to be aware of the complexity of the guide including under what conditions and how it will be implemented.

Judgment of Adequacy

The judgments of adequacy that appear in this report are based on transfer capabilities determined only under the study conditions simulated. These judgments of adequacy are only for a snapshot in time and may be different at other times during the 2004 summer season. When a different set of conditions are simulated, transfer capabilities may be higher or lower than the values used to judge adequacy. All judgments of adequacy are based on MAIN guidelines as stated in MAIN Guide No. 2.

Changes From the Previous Summer Studies

The maximum transfer capability test levels for imports into [redacted] have increased from [redacted] These increases will help to identify limitations [redacted] few were found below the previous maximum test levels.

A new exhibit, Exhibit C-5, has been added. This exhibit contains a summary by MAIN area and surrounding regions of var reserves available based on the 2004 summer peak conditions and generation dispatch as modeled.

[redacted]

LIST OF EXHIBITS

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PART I

OVERVIEW

Introduction

This report is presented in two parts. Part I summarizes the transfer capability of the MAIN transmission system and surrounding systems. This summary consists of individual appraisals for two areas in SMAIN (AMRN and IP), the ALTW area in MAIN, and the three subregions of MAIN (NI, SMAIN and WUMS) as well as interregional appraisals of the MAIN-ECAR-TVA (MET), MAIN-MAPP-SPP (MMS), and MAIN-SERC West (MSw) interfaces. Part II provides details of the tests and models used in the study and the results of major power transfer and transmission element or generator outage simulations. The major transfers and outages simulated have the potential for significant impact on the operations of MAIN and surrounding systems. The list of major transfers and outages in Part II may help in making daily operational decisions.

This study also has a listing of Key Facilities on the MET interface identifying transmission facilities and interregional operating conditions that are critical to the reliability of the interconnected system.

Testing of the MAIN Transmission System

To test the approximate ability of the total MAIN system to interchange power with surrounding regions, the TASG ran computer studies assuming that the subregions of MAIN would contribute the following percentages of the total MAIN export or import.

[redacted] [redacted] [redacted]

These percentages are proportional to the forecasted peak loads of the MAIN area or subregion to the total MAIN regional load.

A detailed listing of generation and load locations used for import and export participation points for each region and subregion is not included in the report but can be found on the MAIN home page under the heading "FERC 715 Filings" and then under the heading "TASG Subsystem Data."

This study was conducted in accordance with MAIN Guide No. 2, dated May 10, 1996, and was based on facility ratings provided by the individual transmission owners. Transmission owners use different rating methodologies. The ratings range from continuous (normal) to ratings that are valid for a specific period of time (emergency).

The ratings shown in Exhibit D-1 are MVA ratings that have been adjusted for var flow in the base case and, therefore, are expressed as MW ratings.

The study results provide a reliability assessment of the transmission system's ability to support regional and subregional imports and exports. **See the section in the front of this report entitled "Understanding and Use of this Report" for further discussion.**

SECTION A

GENERAL OBSERVATIONS AND SUMMARY

Summary

The MAIN Transmission Task Force Steering Committee (TTFSC) judges the interregional nonsimultaneous FCTTC to MAIN from ECAR, MAPP, SERCW, SPP, and TVA to be **adequate** for the 2004 summer period. The judgment of adequacy is based on MAIN guidelines as applied to transfer capability determined for peak load conditions modeled in this study and using applicable operating guides.

A common facility, the [redacted]ransformer (ALTW), limits many tran[redacted] The transformer is sensitive to [redacted] The base case flow on [redacted] 2003 summer study. This is primarily due to an increased [redacted] bias. Updates to local line impedances and an incre[redacted] since the 2003 summer study also contributed to the increase. Additional details on this limitation can be found in the ALTW appraisal, Section B-6.

It is important to note that the transfer capabilities reported in this study are benchmarks to gauge the transmission system strength based on a snapshot of the expected summer peak conditions. The reported values are not intended to be absolute limits to system operation for all system conditions. Therefore, judgment should be used in reviewing these reported transfer levels before assuming that these values are either optimistic or pessimistic for use in daily system operation. **For further understanding, see the section in the front of this report, entitled "Understanding and Use of this Report."**

Operational Considerations

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Expected Interregional Conditions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Following are summaries of the individual MAIN area and subregional appraisals regarding their respective import capabilities for expected 2004 summer peak conditions.

Ameren (AMRN)

[redacted]

Northern Illinois (NI)

[redacted]

Illinois Power (IP)

[redacted]

South MAIN (SMAIN)

[redacted]

[redacted]

Wisconsin-Upper Michigan Systems (WUMS)

[redacted]

Alliant West (ALTW)

[redacted]

The Results of Including IPP/Non-Utility Uncommitted Generation as Export Points

[redacted]

[redacted]

Definitions of Installed Incremental Transfer Capability (IITC), First Contingency Incremental Transfer Capability (FCITC) and First Contingency Total Transfer Capability (FCTTC)

The transfer capability results found here are not the same as the Available Transfer Capability (ATC) or Available Flowgate Capacity (AFC) posted on the appropriate transmission provider's OASIS page. As defined in MAIN Guide No. 2, **IITC** is "the total amount of power above existing or projected schedules that can be transferred on a normal system (i.e., no contingency outages) in a specific direction under the importing system's peak load conditions with no facility loaded above its normal rating." **FCITC** is "the maximum amount of power above existing or projected schedules that can be safely transferred in a specific direction under the importing system's expected peak load conditions without any facility being loaded above its emergency rating and all transmission system voltages remaining within acceptable limits following the outage of the most critical facility." **FCTTC** is defined "as the amount of normal base power transfers plus incremental transfers above the base transfers that can be safely transferred in a specific direction under the importing system's expected peak load conditions without any facility being loaded above its emergency rating and all transmission system voltages remaining within acceptable limits following the outage of the most critical facility."

Limitations on the Use of Reported IITC and FCITC Values

The transfer capability results found here are not the same as the Available Transfer Capability (ATC) or Available Flowgate Capacity (AFC) posted on the appropriate transmission provider's OASIS page.

See the section in the front of this report, entitled "Understanding and Use of this Report," for further discussion.

Assessment of Adequacy

Item A. 2. of the "MAIN Transmission Planning Principles and Guides," MAIN Guide No. 2 states that "Transmission between and within electric systems should have sufficient capability to accommodate projected system requirements and anticipated intra regional, interregional, and transregional real and reactive power flows under normal and credible contingency conditions while not excessively burdening neighboring electric systems." For this purpose, MAIN and its subregions will assess the adequacy of the first contingency total transfer capability (FCTTC) values reported in the seasonal transmission assessment studies performed by the Transmission Assessment Study Group and the interchange capability studies performed by the Future Systems Study Group. The importing party will have the responsibility to assess each FCTTC as adequate, marginally adequate, or inadequate according to the following guidelines.

1) A reported FCTTC value will be presumed adequate unless stated, and argued, otherwise.

2) An assessment of marginally adequate shall indicate that the importing party believes that the given transfer capability value is on the borderline between adequate and inadequate.

3) The importing party may assess an FCTTC as inadequate due to an unfavorable comparison with one or more of the following:

   a) requirements for firm imports or firm transmission service,

   b) maximum transfer anticipated during the study period,

   c) expected level of inrush after the sudden loss of a large generating unit or plant, and

   d) transfer capability required by MAIN Guide No. 6 to maintain system reliability.

4) MAIN as a region and its subregions should expect a geographic diversity in its import options. Thus, a MAIN regional or subregional import capability from a certain direction may be considered inadequate or marginally adequate if it is significantly lower than the import capabilities from other directions and is significantly lower than the amount of capacity that the exporting

region or subregion may be expected to have available in the season.

5) The importing party may consider the ability of the interconnected system to accommodate an unplanned severe condition in assessing its import capability.

6) The importing party may consider the following in assessing its import capabilities:

   a) the trend of its import capabilities in recent TASG studies,

   b) the historical relationship between actual day to day FCTTC values calculated by the MAIN Coordination Center for the importing party and FCTTC values calculated in MAIN's seasonal transmission assessment studies,

   c) the effect of coincident transactions initiated by itself, the exporter, or other parties within or outside of MAIN, and,

   d) the number and complexity of operating guides, particularly of third parties, that would be required to achieve a particular FCTTC.

The MAIN Transmission Task Force Steering Committee (TTFSC) is responsible for assessing the adequacy of MAIN's imports and follows the above guidelines. Each subregion assesses the adequacy of its imports according to guidelines adopted by the individual members of those subregions and applies those guidelines to the import capabilities calculated by TTFSC study groups. Those subregional assessment guidelines, may be based on more detailed planning criteria or guides and operating policies, including those for transfer capability, and may reflect individual system characteristics, geography and demographics, but must, at a minimum, meet the MAIN guidelines. Any additional requirements for the adequacy of import capability of subregions are determined solely by the subregions. Because of differences in subregional assessment guidelines from each other, and from MAIN as a whole, the assessment of one entity may differ from that of another for a similar transfer.

Operating Guides

See the section in the front of this report entitled "Understanding and Use of this Report" for further discussion. All operating guide descriptions are included in Exhibit D-2.

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Exhibits A1 - A3 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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Comparison of the Effects of Redispatch Operating Guides on Nonsimultaneous First Contingency Incremental Transfer Cabability Values

The effect of the following redispatch operating guides has not been verified; however, the next FCITC has been reported assuming the redispatch guide would be effective to that level.

Guide Number and Name**	FCITC with Redispatch Oper. Guide (MW)***	FCITC without Redispatch Oper. Guide (MW)***	Amount Gained By Using Redispatch Oper. Guide (MW)***
23. [redacted]	[redacted]	[redacted]	[redacted]
40. [redacted]	[redacted]	[redacted]	[redacted]
44. [redacted]	[redacted]	[redacted]	[redacted]
63. [redacted]	[redacted]	[redacted]	[redacted]

* Denotes the transfer level studied or based upon the transfer level studied.

** Guide number refers to the number assigned to the guide for consistency in referencing in the report.

*** Zero values may represent negative values and redispatch in the base case may be necessary.

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SECTION B

AREA, SUBREGION AND INTERREGIONAL APPRAISALS

The purpose of this section is to provide details of MAIN areas and subregions, MET, MMS, and MSw import and export capabilities and to discuss critical or limiting facilities.

First Contingency Incremental Transfer Capability (FCITC) values, as determined in this study, are based on a linear load flow technique. AC load flow analysis was performed by individual entities to verify the results of the linear technique on selected transfer capabilities and to confirm adequacy of voltage levels.

The reported nonsimultaneous FCITC is the maximum amount of power in excess of the base interchange schedule (Exhibit C-2) that can be reliably transferred in a specific direction under peak load conditions without any facility becoming loaded above its normal rating in the base case or emergency rating following the outage of the most critical transmission element. In the base case, where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

The nonsimultaneous transfer capabilities provided in Exhibit D-1 are based on an analysis of the modeled transmission system at the time of forecasted peak load. In some cases, the exporting system may be modeled at less than peak load to simulate a high enough level of transfer to adequately test the transmission system. These assumptions emphasize that this study presents an assessment on the state of the transmission system, not the generation system. As such, the FCITC values provided in this report should not be interpreted as indicating either an availability or a deficiency of generating capability that would support or require such a transfer.

Sections B-1 through B-9 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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PART II

DETAILED RESULTS

Introduction

This part highlights the detailed work carried out by the Transmission Assessment Studies Group of the MAIN Transmission Task Force in preparing the study of MAIN for peak conditions modeled during the 2004 summer.

Computer Model of the 2004 Summer Conditions

MAIN, MAPP, SPP, ECAR, TVA and SERCW jointly develop a power flow model to be used for the 2004 MAIN Summer Transmission Assessment Study. This model is used to provide consistent interregional transfer capability results. All of the 100 kV through 765 kV lines and transformers modeled in the defined areas of study were monitored and outaged.

A tabulation of the major lines, transformers, and generating units, additions and changes in MAIN and the surrounding systems since the 2003 summer season, and which are included in the base case power flow model, are shown in **Exhibit C-1**.

All interarea interchange schedules for the 2004 summer period, as represented in this study, are in a table shown in **Exhibit C-2**.

A table of facilities which are overloaded under first contingency without any incremental system transfers are shown in **Exhibit C-3**. For additional information on these facilities, contact the owner of the facility.

Exhibit C-4 is a listing of the model changes requiring re-calculation of transfer capabilities after expiration of the initial time period allowed for submitting model changes.

Exhibit C-5 contains a summary by MAIN area and surrounding regions of var reserves available based on the 2004 summer peak conditions and generation dispatch as modeled.

Simulated Testing of the MAIN Transmission System

The testing criteria used for establishing transfer capability limits and the definitions of these capabilities are contained in MAIN GUIDE NO. 2, "TRANSMISSION PLANNING PRINCIPLES AND GUIDES AND

THE SIMULATION TESTING OF THE MAIN BULK POWER TRANSMISSION SYSTEM TO ASSESS ADEQUACY AND RELIABILITY," dated May 10, 1996.

The reliability of the MAIN Transmission System under extreme disturbance conditions is studied by the Future Systems Study Group utilizing the criteria of MAIN GUIDE NO. 2 and by the individual subregions of MAIN. Conclusions from these studies have been that all areas have adequate transmission to prevent cascading tripping following an extreme disturbance.

Summary of Transfer Capabilities

Summaries of approximate nonsimultaneous Installed Incremental Transfer Capability (IITC) and First Contingency Incremental Transfer Capability (FCITC) for MAIN, the MAIN companies, and adjacent systems along the MAIN interface are shown in **Exhibit D-1.** All transfer capabilities are incremental and are, therefore, in addition to the contracted interchange schedules shown in Exhibit C-2.

Exhibit D-2 provides descriptions of the operating guides referenced in the 2004 MAIN Summer Transmission Assessment Study.

Exhibit D-3 provides a listing of critical facilities affecting MET transfers.

Participation Factors

Section E has been eliminated from this report. Participation factors for this study can be found on the MAIN home page under the heading "FERC 715 Filings" and then under the heading "TASG Subsystem Data."

Glossary of Area, Subregion, Region, and System Designations

A list of the area, subregion, region, and system designations used in this report is given in **Section F.**

SECTION C

DESCRIPTION OF COMPUTER MODEL

The generation, load, and transmission system modeled for this study are those projected for the 2004 summer peak. This section describes the computer model.

Exhibit C-1 contains a list of major transmission lines, transformers, and generator additions and changes that have been placed in service since the 2003 summer season, or are expected to be in service before the 2004 summer peak.

Exhibit C-2 is a table of the base case area interchange schedules.

Exhibit C-3 tabulates the facilities that were identified to overload without incremental transfers for the listed outaged facilities. These facilities may exhibit a response to transfers lower than 3%. Overloaded facilities are screened using linearized contingency calculations.

Exhibit C-4 lists the study iterations and model changes that required re-calculation of transfer capabilities following the expiration of the time period allowed for submitting model changes.

Exhibit C-5 contains a summary by MAIN area and surrounding regions of var reserves available based on the 2004 summer peak conditions and generation dispatch as modeled.

Exhibits C-1, C-2, & C-3 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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EXHIBIT C-4

FACTORS AFFECTING COMPLETION OF 2004 SUMMER STUDY

The following table details the study iterations required to determine the final transfer capability results for the 2004 MAIN Summer Transmission Assessment Study. The iterations correspond to at least one significant change to the power flow model requiring re-calculation of transfer capabilities. The model requiring re-calculation of transfer capabilities. The responsible party identifies the control area or region whose model data required corrections after the scheduled time period for submitting data and corrections.

Study Iteration	Responsible Party	Model Change
1	ALTW ECAR SPP	Corrected modeling of [redacted]
2	ATCLLC, ComEd, ECAR, SERCW ComEd ECAR SPP TVA	Added modeling of operating guides. Corrected contingency modeling. Line and transformer rating corrections. Include modeling of all valid three-winding transformer contingencies in SPP. [redacted]

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Exhibit C-5 consists of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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SECTION D

SUMMARY OF NONSIMULTANEOUS INCREMENTAL TRANSFER CAPABILITIES

This section presents a summary of nonsimultaneous incremental transfer capabilities[1] for imports into MAIN companies and adjacent systems on the MAIN interfaces as determined from the model of the 2004 summer system.

Where a transfer limitation between a MAIN subregion and another region was found to be in a system external to MAIN, the limiting condition was evaluated based on that system's rating criteria. The import capabilities presented have been coordinated with surrounding regions.

The transfer capability results found here are not the same as the Available Transfer Capability (ATC) or Available Flowgate Capacity (AFC) posted on the appropriate transmission provider's OASIS page.

Exhibit D-1 summarizes interarea Installed Incremental Transfer Capability (IITC) and First Contingency Incremental Transfer Capability (FCITC) for MAIN, the MAIN companies and adjacent systems. IITC and FCITC are defined in Section A. Generally, limiting facilities that have a power transfer distribution factor (PTDF) or outage transfer distribution factor (OTDF) of 3 percent or more are listed. However, because of the higher transfer levels tested in this report (up to 4000 or 6000 MW), limiting facilities that impact MET transfers may be listed if they have a PTDF/OTDF of 2.5 percent or more. Both nonsimultaneous IITC and FCITC calculations assume that there are no other transfers taking place other than those described in the base interchange table of Exhibit C-2. **Users should exercise caution in applying the Installed Incremental Transfer Capability since this criteria does not include the effect of a facility outage.**

The key facility outage(s) and the limiting element associated with a particular transfer capability are given along with the flow, rating, and OTDF for the limiting element. This information is listed in the form: **FLOW RATING PTDF/OTDF**. The **FLOW** is the megawatt flow in the limiting element after the occurrence of the outage(s) and before any incremental power transfers. The MW ratings shown in Exhibit D-1 are derived from the facility ratings in MVA that have been adjusted for var flow. The **RATING** is the emergency rating when followed by the letter "E"; and normal or continuous rating when followed by the letter "N." The **PTDF/OTDF**

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1 As defined in MAIN Guide No. 2.

is given for the limiting element after the occurrence of the key facility outage(s).

Incremental transfer capabilities are in addition to the anticipated base interchange schedules shown in Exhibit C-2.

Deviation from these anticipated base schedules, choice of participation points posted on the MAIN website, or other system study conditions can alter base flows and PTDFs and OTDFs affecting the incremental transfer capabilities.

The transfer capabilities provided in this report are based on an analysis of the transmission system only. Therefore, these values should not be interpreted as indicating an availability or deficiency of generating capacity requiring such a transfer.

The simultaneous transfer capability to an area cannot be assumed to equal the sum of the nonsimultaneous transfer capabilities to that area.

Exhibit D-2 provides descriptions of the operating guides included in this study.

Exhibit D-3 is a listing of critical facilities affecting MET transfers. These critical lines are listed by the company owning the limiting line and lists the critical outages as well as the response of the limiting line to outage of the critical line (LODF) and to transfers after the contingency (OTDF).

Exhibits D-1, D-2 & D-3 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

SECTION E

PARTICIPATION FACTORS

This information was not included in this report but can be found on the MAIN home page under the heading "FERC 715 Filings" and then under the heading "TASG Subsystem Data."

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SECTION F
GLOSSARY OF REGION, AREA, AND SYSTEM DESIGNATIONS

AmerGen	AmerGen Energy Company, LLC
DOE	Department of Energy, Paducah, Kentucky
ECAR	East Central Area Reliability Coordination Agreement
ECAR EAST	Eastern ECAR
AP	Allegheny Power
AEBN	Allegheny Energy Buchanan County
AEP	American Electric Power System
AEP-APCO	AEP-Appalachian Power Company
AEP-CSP	AEP-Columbus Southern Power Company
AEP-KGPCO	AEP-Kingsport Power Company
AEP-KPCO	AEP-Kentucky Power Company
AEP-OPCO	AEP-Ohio Power Company
AEP-WPCO	AEP-Wheeling Power Company
DECO	Detroit Edison Company
DELO	Duke Energy Lawrence County Ohio
DEWO	Duke Energy Washington County Ohio
DLCO	Duquesne Light Company
FE	FirstEnergy Corporation
CEI	The Cleveland Electric Illuminating Company
OE	Ohio Edison System
TE	The Toledo Edison Company
IPRV	IP - Riverside
ITC	International Transmission Company
ECAR WEST	Western ECAR
AEP	American Electric Power System
AEP-I&M	AEP-Indiana Michigan Power Company
BREC	Big Rivers Electric Corporation
CIN	Cinergy
AEWC	Allegheny-Wheatland IPP Control Area
CONS	Consumers Power Company
DAYTON	Dayton Power and Light Company
DEVI	Duke Energy Vermilion
EKPC	East Kentucky Power Cooperative
HE	Hoosier Energy Rural Electric Cooperative, Inc.
IMPA	Indiana Municipal Power Agency
IP&L	Indianapolis Power and Light Company
AEWI	Allegheny-Wheatland IPP Control Area
LGEE	Louisville Gas & Electric Energy
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
METC	Michigan Electric Transmission Co. LLC
NIPS	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
SIGE	Southern Indiana Gas and Electric Company
WVPA	Wabash Valley Power Association
Virtual	ECAR Available Generation Pool
EC/NI/SM	ECAR/Northern Illinois/South MAIN Area
EME	Edison Mission Energy
Midwest Generation	Midwest Generation
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council

MAAC	Mid-Atlantic Area Coordination Group
AE	Atlantic Electric
BG&E	Baltimore Gas and Electric Company
DP&L	Delmarva Power and Light Company
JCP&L	Jersey Central Power and Light Company
Intra-PJM	PJM Available Generation Pool
METED	Metropolitan Edison Company
PECO	Philadelphia Electric Company
PENELEC	Pennsylvania Electric Company
PEPCO	Potomac Electric Power Company
PJM500	Pennsylvania-New Jersey-Maryland 500 kV Network
PP&L	Pennsylvania Power and Light Company
PSE&G	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities, Inc.
MAIN	Mid-America Interconnected Network
ALTW	Alliant West
CIPCO	Central Iowa Power Cooperative
NI	Northern Illinois
ComEd	Commonwealth Edison Company
AELC	Allegheny-Lincoln Energy Center IPP Control Area
DELI	Duke Energy Lee County - IPP Control Area
SMAIN	Illinois & Missouri MAIN Systems excluding NI
AMRN	Ameren
AmerenUE	Union Electric
AmerenCIPS	Central Illinois Public Service Company
AmerenCILCO	Central Illinois Light Company (CILC)
CWL	Columbia Water & Light
CWLP	City Water Light and Power, Springfield, Illinois
EEInc	Electric Energy, Incorporated
IMEA	Illinois Municipal Electric Agency
IP	Illinois Power Company
SIPC	Southern Illinois Power Cooperative
SYPC	Soyland Power Cooperative
WUMS	Wisconsin-Upper Michigan Systems
ALTE	Alliant East
ATCLLC	American Transmission Company L.L.C.
CWP	Consolidated Water Power Company
ESE	Edison Sault Electric
MEWD	Marshfield Electric and Water Company
MGE	Madison Gas and Electric Company
MPU	Manitowoc Public Utilities
UPPC	Upper Peninsula Power Company
WE	Wisconsin Electric Power Company System
WPPI	Wisconsin Public Power, Inc.
WPS	Wisconsin Public Service Corporation
MAPP	Mid-Continent Area Power Pool
CAN	Canada
MHEB	Manitoba Hydro-Electric Board
SPC	Saskatchewan Power Corporation

DAK	Dakota Area
MBMPA/MRES	Missouri Basin Energy Services
MDU	Montana-Dakota Utilities Company
MPC	Minnkota Power Cooperative, Incorporated
NWPS	Northwestern Public Service Company
OTP	Otter Tail Power Company
WAPA	Western Area Power Administration
BEPC	Basin Electric Power Cooperative
Intra-MAPP	MAPP Available Generation Pool
IOWA	Iowa Area
MEC	MidAmerican Energy Company
MPW	Muscatine Power and Water Company
MINN	Minnesota Area
DPC	Dairyland Power Cooperative
GRE	Great River Energy
CP	Cooperative Power
UPA	United Power Association
MP	Minnesota Power
NSP/XCEL	Excel Energy Company
SMP	Southern Minnesota Municipal Power Agency
NEBR	Nebraska Area
LES	Lincoln Electric System
NPPD	Nebraska Public Power District
OPPD	Omaha Public Power District
MET	MAIN-ECAR-TVA
MINT	Missouri-Iowa-Nebraska Transmission
MMS	MAIN-MAPP-SPP
MSw	MAIN-SERC West
NPCC	Northeast Power Coordinating Council
CORNWALL	Cornwall
HQTE	Hydro-Quebec TransEnergie
IMO	Independent Electricity Market Operator
NB	New Brunswick Power
NS	Nova Scotia Power
NEPOOL	New England Power Pool
NYISO	New York ISO
OH	Ontario Hydro
SERC	Southeastern Electric Reliability Council
SERCW	SERC West
AECI	Associated Electric Cooperative, Incorporated
BCA	DVP-Batesville IPP Control Area
DENL	Duke Energy, North Little Rock
ESI	Entergy Services, Inc
EAI	Entergy Arkansas, Inc
EGSI	Entergy Gulf States, Inc
ELI	Entergy Louisiana, Inc
EMI	Entergy Mississippi, Inc
ENOI	Entergy New Orleans, Inc
LAGN	Louisiana Generating Company
SOUTHERN	Southern Subregion of SERC
AEC	Alabama Electric Cooperative
DEMT	Duke Energy Murray Plant Control Area
SMEPA	South Mississippi Electric Power Association
SOCO	Southern Company

TVA	Tennessee Valley Authority
VACAR	Virginia - Carolinas Subregion of SERC
CPLE	Carolina Power & Light Company-East
CPLW	Carolina Power & Light Company-West
DUKE	Duke Energy
SCEG	South Carolina Electric & Gas Company
SC	South Carolina Public Service Authority
SEPA	Southeastern Power Administration
SEHA	Hartwell Power Plant
SETH	Thurmond Power Plant
SERU	Russell Power Plant
DVP	Dominion Virginia Power
YAD	Yadkin, Inc.
SPP	Southwest Power Pool
SPP-N	North SPP (KS/MO)
EDE	Empire District Electric Company
INDN	City Power & Light, Independence, Missouri
KACY	Board of Public Utilities, Kansas City, KS
KCPL	Kansas City Power and Light Company
MIDW	Midwest Energy, Incorporated
MPS	Missouri Public Service Company
SECI	Sunflower Electric Cooperative
SPRM	City Utilities, Springfield, Missouri
WR	Western Resources, Incorporated
WPEK	West Plains Energy
SPP-S	South SPP (AR/LA/NM/OK/TX)
AECC	Arkansas Electric Cooperative Corporation
AEPW	American Electric Power System
CLEC	Central Louisiana Electric Company, Incorporated
GRDA	Grand River Dam Authority
LAFA	City of Lafayette
LEPA	Louisiana Energy & Power Authority
OKGE	Oklahoma Gas and Electric Company
OMPA	Oklahoma Municipal Power Authority
SPA	Southwestern Power Administration
SPS	Southwestern Public Service Company
WFEC	Western Farmers Electric Cooperative
WSCC	Western Systems Coordinating Council

MID-AMERICA INTERCONNECTED NETWORK, INC.

April, 2004

REGULAR MEMBERS

Allegheny Energy Supply Co., LLC
Alliant Energy Corporate Services
Ameren Services Company
American Transmission Company, LLC
Central Iowa Power Cooperative
City Water, Light and Power
Columbia (Missouri) Water & Light
Commonwealth Edison Company
Constellation Power Source, Inc.
Coral Power, LLC
Duke Energy North America, LLC
Edison Mission Marketing and Trading
El Paso Merchant Energy
Electric Energy, Inc.
Illinois Municipal Electric Agency
Illinois Power Company
LG&E Energy Marketing, Inc.
Madison Gas & Electric Company
Midwest ISO
Mirant Americas, Inc.
Northern Indiana Public Service Co.
NRG Energy, Inc.
PG&E Corp.
PJM Interconnection, LLC
PPL EnergyPlus, LLC
Reliant Energy Services
Sempra Energy Trading
Southern Illinois Power Co-operative
Soyland Power Cooperative, Inc.
Tenaska Power Services
Tractebel Energy Marketing, Inc.
Williams Power Company, Inc.
Wisconsin Electric Power Company
Wisconsin Public Power Inc.
Wisconsin Public Service Corporation

ASSOCIATE MEMBERS

BP Energy Company
Cargill Power Markets, LLC
Cinergy Corp.
Entergy-Koch Trading L.P.
FirstEnergy Solutions Corp.
GridAmerica, LLC
TXU Energy Trading Company

Mid-America Interconnected Network, Inc.
939 Parkview Boulevard
Lombard, Illinois 60148-3267
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http://www.maininc.org

Summer 2004 VEM and MEN Interregional Transmission System Reliability Assessment Report Summaries

Attached for your information are highlights from the 2004 Summer VACAR-ECAR-MAAC (VEM) and MAAC-ECAR-NPCC (MEN) reports. These assessments reflect evolving market alliances and system operations that do not completely mirror NERC reliability regions. Both Interregional Transmission System Reliability Assessments reflect the integration of PJM West into the PJM energy market operation for import and export simulations. In addition, a portion of Orange and Rockland Utilities Inc. load, located in New Jersey, was incorporated into PJM's pool operations during March 2002.

Major changes in modeling from the 2003 Summer Base Case to the 2004 Summer Base Case include:

Additions:

- Approximately [redacted] of new [redacted] within [redacted]
- Approximately [redacted] of new [redacted] within [redacted]
- Approximately [redacted] of new [redacted] within [redacted]
- Approximately [redacted] of [redacted] has been added in [redacted]

Net Interchanges:

- [redacted]

As the evolution of the interconnected network continues, the Operating Limits for flowgates along the ECAR, MAAC and VACAR interfaces have been changed. On May 1, 2004, Commonwealth Edison was incorporated into the PJM market and AEP and Dayton P&L are expected to join in the early Fall, 2004. Potentially, Dominion Virginia Power may also join as early as November, 2004 and Duquesne P&L by January, 2005. As such, the boundaries of PJM are moving significantly beyond those of the MAAC region. For the 2004 Summer Study a [redacted] transfer was included in the MEN/VEM base case to account for the transmission reservation from the ComEd system to the eastern portion of the PJM system representing the ComEd PJM market integration pathway.

A high level summary of the results contained in each report are:

MEN:

Comparison of the limits reported in the assessment with those reported in previous assessments must be tempered with the realization that the study results reflect different operations due to different market alliances. However; qualitative comparisons are discussed in this assessment where appropriate and highlighted below.

The MEN transfer limits are sensitive to the [redacted] The [redacted] are modeled in a manner consistent with the last several MEN Assessments. The 2004 Summer MEN Assessment reflects the current status of the [redacted]

[redacted]

The MEN 2004 Summer Study has identified thermal limits to interregional transfers in several portions of the system. [redacted] and [redacted] transfers are limited by facilities in the vicinity of the [redacted] Some limiting facilities include:

- [redacted]

[redacted] transfers are limited by facilities in [redacted]

- [redacted]

[redacted] transfers are limited by the [redacted] circuit in [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

VEM:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

APPENDIX A

SYSTEM DESCRIPTION AND BASE CASE CONDITIONS

This Appendix includes detailed one-line drawings and other descriptions of the base case used to conduct the VEM 2004 Summer Transmission Assessment.

Page(s) A-2 to A-21 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

APPENDIX B

SYSTEM RESPONSE FACTORS

This Appendix includes the interconnected system response factors for selected interfaces and an index of key facilities.

Page(s) B-2 to B-20 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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APPENDIX C

TRANSFER DISPATCHES

This Appendix includes the regional and subregional transfer dispatches used in calculating transfer capabilities.

Page(s) C2 to C-11 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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APPENDIX D

REGIONAL OPERATING PROCEDURES

This Appendix includes regional operating procedures and voltage limitation curves.

Page(s) D-2 to D-7 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

They have been deleted from this copy.

APPENDIX E

DEFINITIONS

This Appendix includes a glossary of terms, transfer capability discussion and example, and a system abbreviation list.

Glossary of Terms

FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GSRF	Generation Shift Response Factor
LODF	Line Outage Distribution Factor
NITC	Normal Incremental Transfer Capability
NUG	Non-Utility Generator
OTDF	Outage Transfer Distribution Factor
PAR	Phase Angle Regulator
PTDF	Power Transfer Distribution Factor
TLR	Transmission Loading Relief
RTO	Regional Transmission Organization
ISO	Independent System Operator
ATC	Available Transfer Capability
TTC	Total Transfer Capability
CBM	Capacity Benefit Margin
TRM	Transmission Reliability Margin

Transfer Capability Discussion

The transfer capabilities determined in this report were defined in the May 1995 North American Electric Reliability Council (NERC) publication "Transmission Transfer Capability" as follows:

Normal Incremental Transfer Capability (NITC)

The amount of electric power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-contingency loading reach the normal thermal rating of a facility prior to any first contingency transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

First Contingency Incremental Transfer Capability (FCITC)

The amount of electric power, incremental above normal base power transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loading are within normal ratings and all voltages are within normal limits,

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loading are within emergency ratings and all voltages are within emergency limits.

First Contingency Total Transfer Capability (FCTTC)

The total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission systems in a reliable manner based on conditions 1, 2, and 3 in the FCITC definition above.

Excluded Limitations

Transfer capability is determined by the overall system, including all network facilities. There will be occasions, however, when loading of non-bulk power facilities restricts calculated transfer capability. As recommended in the May 1995 NERC publication "Transmission Transfer Capability", such limitations are excluded from the results published in this report only if: a) there is an established operating procedure to eliminate the overload condition (such as those addressed under Regional Operating Procedures in Appendix D); or b) the facility involved has minimal effect on the bulk power supply system. Transfer response of less than 3.0% to the transfer being studied is taken as prima facie evidence of minimal effect.

Normal Incremental Transfer Capability (NITC) Calculation Example

Note: This is an example of the calculation procedure. The numbers used in the calculation do not reflect conditions modeled in this study.

Example 1: Pre-Contingency Limitation

TRANSFER:	ECAR to VP
Transfer Test Level:	2,000 MW
Monitored Facility:	[redacted]
Rating of Monitored Facility:	2600 MW, 24 hours system normal 3012 MW, long-term emergency

1) Results of Power Flow Simulation:

	Base Flow	Transfer Flow
[redacted]	1900 MW	2328 MW

2) Power Transfer Distribution Factor:

PTDF = [Transfer Flow - Base Flow] / [Transfer Level]

PTDF = [2328 - 1900] / [2000]

PTDF = 0.214

NITC = [Normal Rating Monitored Facility - Base Flow Monitored Facility] / PTDF

NITC = (2600 - 1900) / (0.214)

NITC = 3274 MW

First Contingency Incremental Transfer Capability (FCITC) Calculation Example

Note: This is an example of the calculation procedure. The numbers used in the calculation do not reflect conditions modeled in this study.

Example 2: Contingency Limitation

TRANSFER:	ECAR to VP
Transfer Test Level:	2,000 MW
Monitored Facility:	[redacted]
Contingency:	
Rating of Monitored Facility:	2600 MW, 24 hours system normal 3012 MW, long-term emergency

1) Results of Power Flow Simulation:

	Base Flow	Transfer Flow	Post-Contingency Transfer
[redacted]	1900	2328	3203
	1678	1979	----

2) Calculation of Power Transfer Distribution Factors (PTDF):

PTDF = [Transfer Flow - Base Flow] / Transfer Level

a) [redacted] PTDF = (2328-1900)/(2000)
PTDF = 0.214

b) [redacted] PTDF = (1979-1678)/(2000)
PTDF = 0.151

3) Calculation of Line Outage Distribution Factor (LODF):

LODF = [Post-Contingency flow on monitored facility - Pre-Contingency flow on on monitored facility] / [Pre-Contingency flow on facility outaged]

LODF of [redacted]

LODF = (3203-2328)/1979

LODF = 0.442

4) Outage Transfer Distribution Factor (OTDF):

OTDF = Superposition of the PTDF of monitored facility and the contributing PTDF of the outaged facility

OTDF = [PTDF of [redacted] + (LODF) (PTDF of [redacted]

OTDF = 0.214 + (0.442)(0.151)

OTDF = 0.281

5) Post-Contingency Base Flow on Monitored Facility:

[Base Flow] + (LODF) [Base Flow of facility outaged]

= 1900 + (0.442) (1678)

= 2642 MW

FCITC = [Limiting Rating of Monitored Facility - Post-Contingency Base Flow Monitored Facility] / (OTDF)

FCITC = [3012 -2642] / (0.281)

FCITC = 1317 MW

System Abbreviations

Organizations

ECAR	**East Central Area Reliability Coordination Agreement**
AEBN	Allegheny Energy Buchanan County
AEP	American Electric Power System
BREC	Big Rivers Electric Corporation
CIN	The Cinergy Electric Company
DEVI	Duke Energy N.A., Vermillion
DELO	Duke Energy L.O.
DEWO	Duke Energy Washington County Ohio
DLCO	Duquesne Light Company
DPL	The Dayton Power and Light Company
EKPC	East Kentucky Power Cooperative, Inc.
AEWC	Allegheny Energy Supply Co., Wheatland-Cinergy
AEWI	Allegheny Energy Supply Co., Wheatland-IPL
FE	First Energy Corporation
HE	Hoosier Energy Rural Electric Cooperative, Inc.
IPL	Indianapolis Power & Light Company
IPRV	IP Riverside
LGEE	Louisville Gas & Electric Company (LGE Energy)
MECS	Michigan Electric Coordinated System
METC	Michigan Electric Transmission Company (Consumers Energy)
ITC	International Transmission Company (The Detroit Edison Company)
NIPS	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
SIGE	Southern Indiana Gas and Electric Company (Vectren)
FRCC	**Florida Reliability Coordination Council**
PJM	**PJM Interconnection LLC**
MAAC	**Mid-Atlantic Area Council**
BGE	Baltimore Gas and Electric Company
FE	First Energy Corporation
JC	Jersey Central Power & Light Company
ME	Metropolitan Edison Company
PN	Pennsylvania Electric Company
PE	PECO Energy
CV(AE)	Conectiv (Atlantic Electric)
CV(DP&L)	Conectiv (Delmarva Power & Light Company)
PEPCO	Potomac Electric Power Company
PPL	PPL Electric Utilities Corporation
PS	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities, Inc.
PJM WEST (ECAR Company)	
AP	Allegheny Power

System Abbreviations (continued)

MAIN	**Mid-America Interconnected Network**
NI (CE)	Commonwealth Edison
MAPP	**Mid-Continent Area Power Pool**
MEN	MAAC-ECAR-NPCC
NERC	**North American Electric Reliability Council**
NERC-MMWG	North American Electric Reliability Council - Multiregional Modeling Working Group
NPCC	**Northeast Power Coordinating Council**
HQ	Hydro-Quebec
ISONE	ISO New England, Inc.
NSPC	Nova Scotia Power Incorporated
NB	New Brunswick Power
NYISO	New York ISO
SENY	Southeastern New York Companies
C HUDS	Central Hudson Gas & Electric Corporation
CON ED	Consolidated Edison Company of New York, Inc.
LIPA	Long Island Power Authority
NYPA	New York Power Authority *
O&R	Orange & Rockland Utilities, Inc.
UPNY	Upstate New York Companies
NYSEG	New York State Electric and Gas Corporation
NMPC	Niagara Mohawk Power Corporation
NYPA	New York Power Authority*
RG&E	Rochester Gas and Electric Corporation
IMO	Independent Electricity Market Operator in Ontario

* NYPA has load and generation in both SENY and UPNY

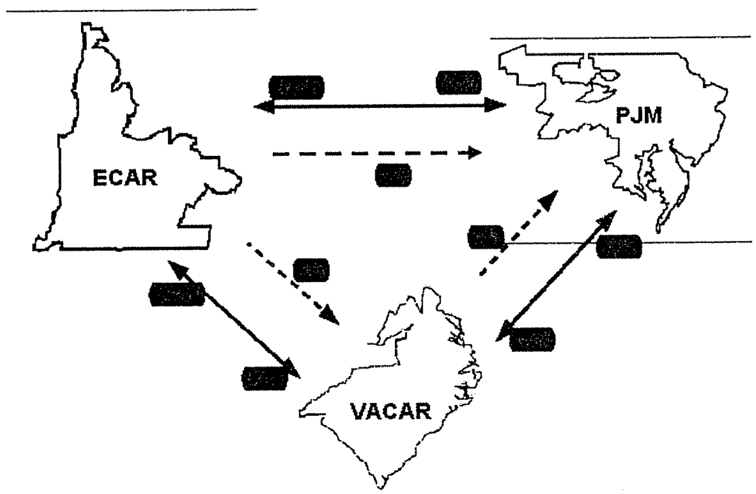
PJM	PJM Interconnection, LLC
PJM W	PJM West

System Abbreviations (continued)

SERC	**Southeastern Electric Reliability Council**
SOUTHERN SUBREGION	
AEC	Alabama Electric Cooperative, Inc.
SOCO	Southern Electric Systems
GTC	Georgia Transmission Co.
TVA	Tennessee Valley Authority
VACAR	**Virginia-Carolina Systems**
CPLE	Carolina Power & Light - East
CPLW	Carolina Power & Light - West
DUK	Duke Energy
SCEG	South Carolina Electric & Gas Company
SCPSA	South Carolina Public Service Authority
VAP	Dominion Virginia Power
ENTERGY SUBREGION	
AECI	Associated Electric Cooperative, Inc.
CAJUN	Cajun Electric Power Cooperative, Inc.
ENTERGY	Entergy
ODEC	Old Dominion Electric Cooperative
DOE	Department of Energy
SMEPA	Southern Mississippi Electric Power Association
NCEMC	North Carolina Electric Membership Corporation
SEPA	Southeastern Power Administration
SPP	**Southwest Power Pool**
VAST	VACAR-AEP-SOUTHERN-TVA-ENTERGY
VEM	**VACAR-ECAR-MAAC**

VACAR-ECAR-MAAC
STUDY COMMITTEE

2004 SUMMER
VEM INTERREGIONAL
TRANSMISSION SYSTEM
RELIABILITY ASSESSMENT



May 2004

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VACAR-ECAR-MAAC Study Committee

N. K. Burks	Dominion Virginia Power	VACAR
D. B. Guy	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	VACAR
S. P. Lockwood	American Electric Power	ECAR
R. W. Johnson	Allegheny Power	ECAR
N. O. Halladay (Chairman)	PJM Interconnection, L.L.C.	MAAC

VACAR-ECAR-MAAC Working Group

N. K. Burks (Chairman)	Dominion Virginia Power	VACAR
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R. W. Johnson	Allegheny Power	ECAR
B. C. Taberner	American Electric Power	ECAR
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VACAR - ECAR - MAAC 2004 Summer Transmission Assessment

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VACAR - ECAR - MAAC 2004 Summer Transmission Assessment

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Appendices

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Appendices

REPORT ON THE VEM 2004 SUMMER INTERREGIONAL TRANSMISSION SYSTEM RELIABILITY ASSESSMENT

1. INTRODUCTION

This report documents results of the VACAR, ECAR, and MAAC 2004 Summer Interregional Transmission System Reliability Assessment, which was conducted to assess the anticipated performance of the VEM bulk transmission system during the 2004 summer peak load period. It is one of a continuing series of studies made under the Inter-Area Reliability Coordination Agreement among the VEM areas to provide a periodic analysis of the effects on system performance of changes in generation, transmission, and in area loads as well as other developments in system conditions.

This study, as did the 2003 summer study, analyzes transfers to and from PJM (including AP) and ECAR (excluding AP). Previous studies looked at transfers to and from the traditionally defined MAAC and ECAR regions.

In addition this report contains results of power flow testing of system contingencies under bulk power transfer conditions, including NON-SIMULTANEOUS transfer capabilities, the identification of key facilities, voltage limitation curves, outage and transfer response factors, and power flow diagrams. It also includes some analysis of the potential effects of SIMULTANEOUS transactions on VEM transfer capabilities.

The transfer capabilities reported in this study represent a set of simulated conditions based on a prediction of many factors that change in the daily operation of the system. They represent one possible method to compare and measure the relative strength of the system from one season or study period to the next. Actual transfer capabilities will vary from those calculated. Response factors and other operating guides are, therefore, included in this report to aid system operators in the daily operation of the interconnected network. The variable factors include:

- Load forecasts
- Generation availability
- Geographic distribution of load and generation
- Transmission system configuration
- Concurrent power transfers

The transfer limits in this report are not the Available Transfer Capabilities (ATC) or the Total Transfer Capability (TTC) as required in FERC Order 888 and 889 and posted on the OASIS nodes. While ATC and VEM transfer capabilities are both based on next-contingency analysis, numerous differences in the study scope and included assumptions make valid comparison of these transfer capability values impossible. These differences, which may vary with the time horizon, include:

- **Scope**: ATC is calculated by transmission providers, which generally corresponds to the control area level; VEM studies are calculated at the NERC regional level.

- **Coordination:** ATC is calculated by transmission providers using system representations and procedures they deem appropriate. Transfer capacity is calculated by VEM using the most up-to-date NERC system representation and procedures established by all three regions.
- **Margins**: ATC determination uses margins (TRM/CBM) to provide for variation in system operating conditions; VEM reports FCITCs without applying margins.
- **Tie Capacity**: ATC between adjacent control areas is limited by scheduling limits based on the tie capacity between control areas; VEM reports inter-regional network transfer capabilities regardless of scheduling limits between individual control areas.
- **Timeframe**: ATC is calculated hourly, daily, weekly, and monthly; VEM studies are conducted semi-annually based on a snapshot of anticipated conditions.
- **Publishing**: ATC is posted to an OASIS for use by the commercial markets; VEM study results are published for use as an interregional reliability assessment.

Additionally, as the VEM study results documented in this report are based on only one set of "forecasted" conditions for the study period, they should not be considered absolute or optimal.

2. RESULTS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

RESULTS

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

Double Contingencies

[redacted]

Key Facilities

[redacted]

B. COMPARISON OF 2004 SUMMER WITH 2003 SUMMER RESULTS

The differences between the 2004 Summer and the 2003 Summer FCTTCs and FCITCs are provided in Table 2. It should be noted that there were no changes in study procedures for this study. The analyses followed the same study procedures that have been in use for the past several studies.

A comparison of the import limits, including the primary factors contributing to any increases or decreases are explained in detail below.

> The transfer limits in this report are not the Available Transfer Capabilities (ATC) or the Total Transfer Capability (TTC) as required in FERC Order 888 and 889 and posted on the OASIS nodes. While ATC and VEM transfer capabilities are both based on next-contingency analysis, numerous differences in the study scope and included assumptions make valid comparison of these transfer capability values impossible.
>
> Additionally, as the VEM study results documented in this report are based on only one set of "forecasted" conditions for the study period, they should not be considered absolute

or optimal. These limits provide one possible method to compare and measure the relative strength of the system from one season or study period to the next.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

SUBREGIONAL IMPORT LIMITS

[redacted]

[redacted]

[redacted]

C. DISCUSSION OF RESULTS

NERC Book of Flowgates

In this study, a separate linear power flow run was performed for each transfer while monitoring facilities contained in the NERC Book of Flowgates. No facility that was not already monitored appeared as a valid limit ahead of the reported VEM limit for any transfer.

Non-Simultaneous Transfers

Table 2 compares the 2004 Summer NON-SIMULTANEOUS regional and subregional FCITCs and FCTTCs with those projected for last summer. Table A-1 lists the assumed base power interchanges among the VEM Regions.

Simultaneous Transfers

With the highly integrated nature of the VEM network, power transfers between areas will change power flows throughout all three VEM regions. In some cases, the resulting power flow in a part of the region not involved in the transfer can be significant. When considered alone, these transfers may not appear to pose a problem. However, for certain combinations of simultaneous power transfers, portions of the VEM network could experience significant power flow increases on facilities identified as limits to interregional transfers when the responses to the simultaneous transfers are in the same direction.

D. SIMULTANEOUS TRANSFER CAPABILITY PLOTS

[redacted]

[redacted]

[redacted]

[redacted]

RESULTS

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

F. ESTABLISHED OPERATING PROCEDURES

Operating procedures have been established that prevent certain transmission facilities from restricting interregional power transfer. Appendix D of this report describes these procedures.

G. EXHIBITS

The following exhibits summarize the results of this study:

Table 1	First Contingency Incremental Transfer Capability (FCITC)
Table 2	Comparison of 2004 Summer vs. 2003 Summer Transfer Limits
Figure 1	Non-Simultaneous Interregional Power Transfers
Figure 2	Plot of Simultaneous Total Transfer Capability (Fig A-D)
Figure 3	Plot of Non-VEM Simultaneous Total Transfer Capability (Fig A-H)
Figure 4	Location of Limiting Facilities

Page(s) 11 - 14 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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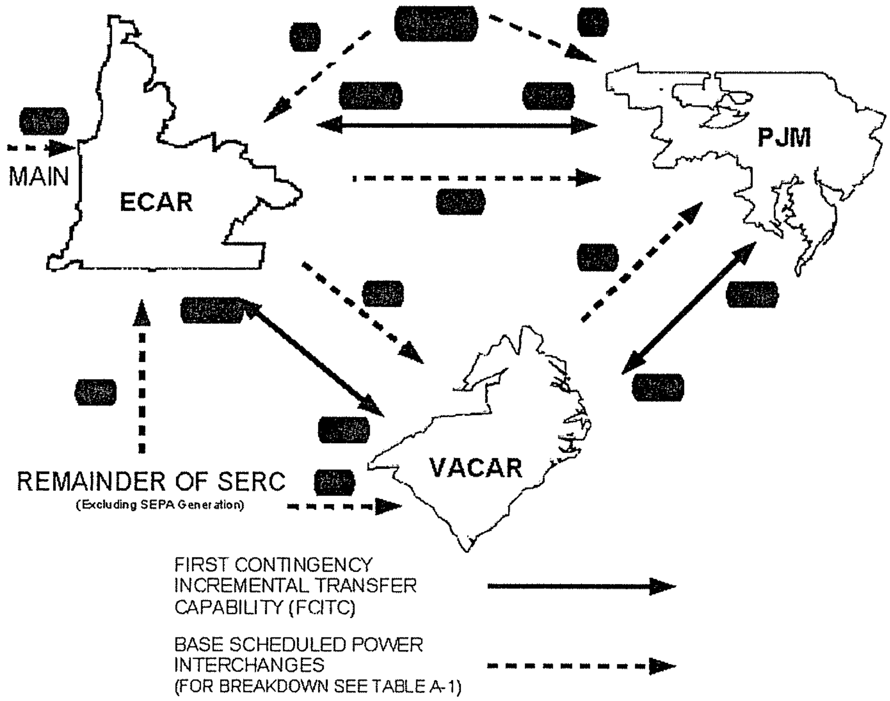
Figure 1

NON-SIMULTANEOUS
INTERREGIONAL POWER TRANSFERS (MW)
PEAK LOAD CONDITIONS



* Base transfer number does not reflect [redacted] transfer modeled in base case

Page(s) 16 - 22 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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3. BACKGROUND INFORMATION

The VACAR-ECAR-MAAC (VEM) study area covers 12 states stretching from Indiana and Kentucky, east to New Jersey, and south to South Carolina. Despite the wide geographic expanse, the area is closely coupled electrically by extensive EHV transmission facilities.

During other than peak conditions, the transmission network, which integrates the VEM area, has a [redacted] in power flows that is caused by many factors including:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Recently, interchange of power at peak load has become extremely sensitive to electricity prices. The result of this price sensitivity is that small differentials of price can cause large interchange of power in the more historical [redacted] direction or also in an [redacted] direction. [redacted] interchanges have also occurred.

In light of the considerable exchange of power between the VEM regions, interfaces have been identified which are monitored to control the flows to reliable levels. Critical flow conditions may cause limits for transfers within the VEM area.

Three of these interfaces, [redacted] imports. These interfaces, which are shown in Figure B-1, consist of [redacted] lines that carry a large portion of the transfers. [redacted]

[redacted] In all of the simulations conducted for this study, a [redacted] wheeling schedule was maintained through [redacted]

Facilities in eastern [redacted] shown in Figure B-1) are highly responsive to [redacted] As a result, these facilities may reach their reliable loading limits. Under those conditions, [redacted] will need to be either frozen or curtailed to safe levels. The TLR, a step-by-step procedure developed by the NERC Operating Reliability Subcommittee (ORS) for preventing transmission overloads and curtailing transmission transactions, will be implemented to avoid or relieve any overload which cannot be relieved by PJM redispatch. The TLR identifies the actual transactions, by priority and use, which cause Operating

Security Limit violations. The TLR considers the actual paths over which transactions are flowing, not their contract paths, to determine which transactions to curtail and or freeze. More information about the TLR may be obtained from the NERC home page at www.nerc.com.

Operating experience indicates the [redacted] Other actions to maintain reliability in the area are summarized under the Special Transmission Emergency Procedures (STEP) in Appendix D.

[redacted]

A. BASE CASE DEVELOPMENT

A VEM/MEN peak load level base case was developed from the 2003 series NERC-MMWG 2004 Summer base case. System models in VACAR, ECAR, PJM, and NPCC were updated to reflect the most recent projected system schedules and conditions. Base case transfers from ECAR to PJM, NPCC to PJM, VACAR to PJM, and ECAR to VACAR were modeled to reflect firm capacity backed transfers. Table A-1 shows the changes in transfers from last summer's operating study. Table A-2 indicates changes in the interregional transfers of extraterritorial generation and load from the 2003 Summer Transmission Assessment.

B. STUDY PROCEDURE

Interregional system performance during regional and subregional power transfers, for both normal and single contingency conditions, following the 1995 NERC transfer capability definitions (Appendix E), was analyzed using linear power flow techniques on the base case. Voltage restrictions were identified using AC power flow analysis where necessary. FCTTCs were determined for all regional transfers by adding the scheduled regional base case transfers to the FCITCs.

The effects of selected multiple outages and simultaneous transfers on VEM system performance were also examined using AC and linear power.flow analysis. Incremental loadings on key transmission facilities caused by each of several simultaneous transfers were monitored to determine the effect of simultaneous transfer activity on interregional transfer capabilities.

The Key Facilities Index, Table B-1, lists the facilities found in this study to be most critical to the performance of the VEM systems. The index identifies the change conditions to which these facilities are most responsive. Transfer response factors for key transmission paths were determined and can be found in Appendix B.

Page(s) 26 - 34 consist of information defined as Critical Energy Infrastructure Information (CEII) in FERC Order 649.

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